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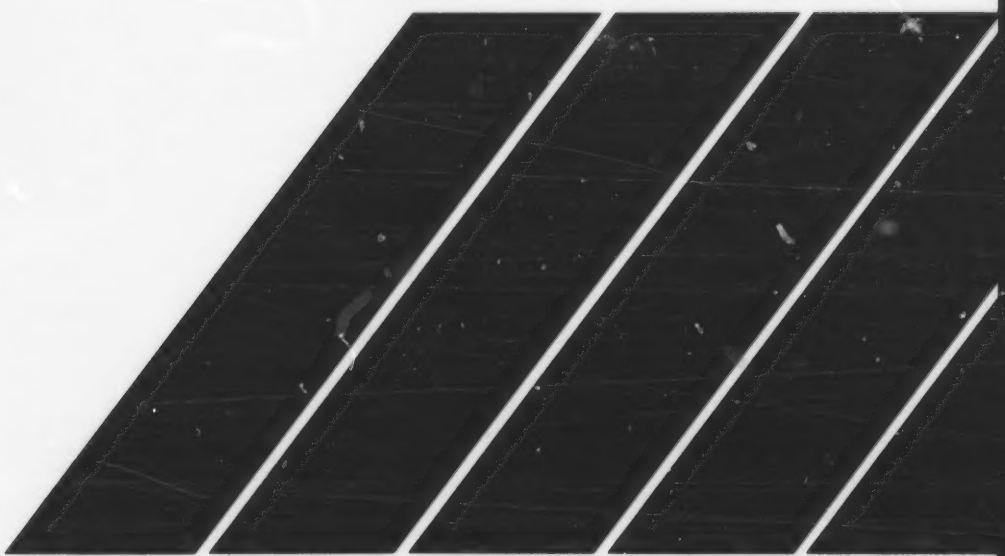

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SUPPLY AND DEMAND SIDE BENEFITS OF SOLAR DOMESTIC HOT WATER SYSTEMS: PHASE I

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Executive Summary

Based on forecasted increases in electricity demand, several utilities within Canada will be faced with capacity shortages within the next decade. These utilities are therefore evaluating demand management strategies which could reliably reduce peak power requirements and defer or reduce the construction of new generating facilities. Major generating projects can cost billions of dollars and hence, deferred construction can save a utility millions of dollars in interest charges alone. Reducing the demand for electricity also helps to minimize the negative environmental impacts which are associated with conventional energy production.

For these reasons, Energy, Mines and Resources Canada has commissioned a study to assess the potential for peak load reduction through residential solar water heating. The study was intended to analyze both existing and innovative solar system designs according to four utility-oriented evaluation criteria: (1) peak reduction capability, (2) reductions in energy consumption at different utility demand levels, (3) impact on load factor and, (4) the ability to supply hot water under typical and extreme load conditions.

Results have identified a single family residential system with the potential to reliably displace 942 W of capacity requirement, and 4.19 MWh of energy per year. At a solar system penetration rate of 20% in Ontario for example, this represents utility capacity and annual energy demand reductions of over 200 MW and 952 GWh respectively. The ability to accomplish this without a corresponding reduction in load factor has also been noted. Based on these numbers and the system incremental costs of energy and power for a typical Canadian utility, the avoided cost of energy and power for this system was calculated at $2723. Because this represents the majority of the installed system cost, increased utility involvement in the implementation of solar water heating technologies appears to be warranted.

Sommaire

Si les prévisions de la hausse de la demande d'électricité se réalisent, plusieurs entreprises canadiennes de services publics seront à court de capacité de production d'ici une dizaine d'années. D'où l'exercice qu'elles ont entrepris d'évaluer des stratégies de gestion de la demande qui permettraient de réduire sans crainte la puissance de pointe requise et de reporter, temporairement ou indéfiniment, la construction de nouvelles centrales. La facture des grands ouvrages de production pouvant s'élever à des milliards de dollars, le fait d'en reporter la construction permettrait à une entreprise d'épargner des millions de dollars juste en frais d'intérêts. La diminution de la demande d'électricité contribue également à atténuer la dégradation de l'environnement causée par la production d'énergie classique.

Pour ces raisons, le ministère de l'Énergie, des Mines et des Ressources a commandé une étude visant à évaluer les possibilités de réduction de pointe de charge par l'installation de systèmes de chauffage solaire en milieu résidentiel. Les auteurs de l'étude devaient analyser des systèmes de chauffage solaire existants et nouveaux en fonction de quatre critères d'évaluation centrés sur les services publics : (1) capacité à réduire la pointe de charge, (2) réductions de la consommation d'énergie pour différents niveaux de la demande, (3) impact sur le facteur de charge et (4) capacité à fournir de l'eau chaude dans des conditions ordinaires et extrêmes de la demande.

Les résultats de l'étude ont montré qu'un système de chauffage installé sur une maison unifamiliale pouvait sans problème soulager le réseau de 942 W de capacité et 4,19 MWh d'énergie par année. À un taux de pénétration du solaire de 20 %, en Ontario par exemple, cela donne une réduction de plus de 200 MW de la capacité d'une entreprise de services publics et une diminution annuelle de la demande d'énergie de 952 GWh. Le rapport note également que ces réductions sont possibles sans une diminution correspondante du facteur de charge. Compte tenu de ces chiffres, et si l'on considère en plus les coûts supplémentaires en énergie et en puissance pour une enteprise moyenne de services publics au Canada, le coût éludé de l'énergie et de la puissance est estimé à 2 732 $. Or, comme ce chiffre représente la plus grande partie du coût d'un système après installation, une participation accrue des services publics à la mise en oeuvre des techniques de chauffage solaire semble justifiée.

1 INTRODUCTION

1.1 BACKGROUND

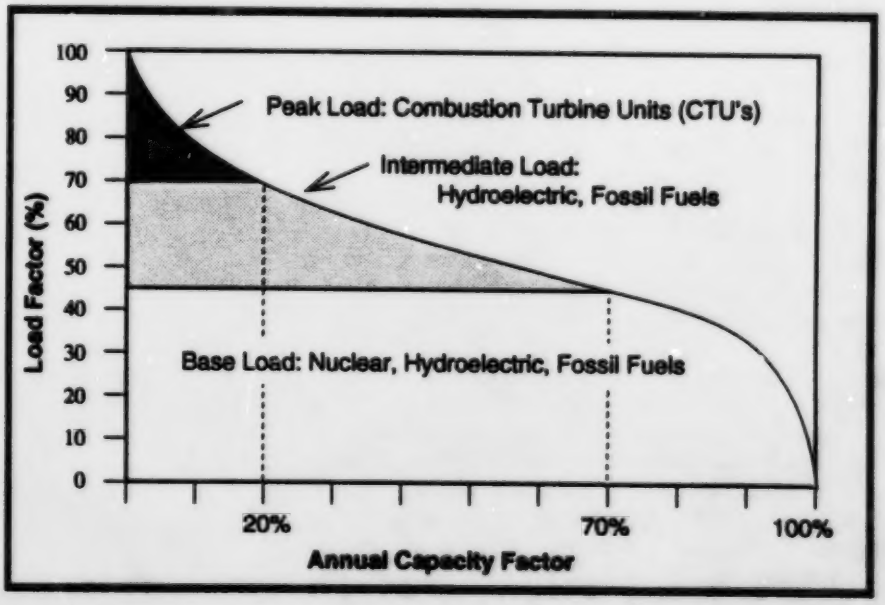
Electrical utilities generally categorize their system loads according to the frequency at which they must be supplied. For example, Ontario Hydro defines its base, intermediate and peak loads as those which must be met greater than 70%, between 20% and 70%, and less than 20% of the time respectively [1]. This is illustrated in Figure 1-1 which is an annual load duration curve for a typical Canadian utility. In the figure, base and intermediate loads are shown to be supplied using nuclear, hydroelectric and fossil fuel fired generation. At annual capacity factors (ACF)[1] above 20%, these are generally the lowest cost supply options.

1. Annual energy produced by a facility divided by the energy it would produce if operated continuously at full power.

For peak generation, where the annual capacity factor of the supply option is lower than 20%, gas-fuelled combustion turbine units (CTU's) are generally used. These are characterized by a lower capital investment requirement, and lower life-cycle costs per unit of energy produced. However, CTU's also have higher fuelling and operating costs than the other alternatives which, in Ontario for example, result in levelized unit energy production costs between $0.07/kWh and $0.20/kWh. These are costs which are clearly not recovered at normal utility billing rates. This discrepancy, combined with the need for guaranteed supply during peak periods, places major emphasis on the development of alternatives which are primarily intended to offset peak loads.

Figure 1-1

Typical Utility Annual Load Duration Curve



Traditionally, the peak demand for electricity in Ontario has occurred during the winter periods. However in some of the urbanized regions of the province, the peak is shifting to the summer months due to significantly increased cooling loads [2]. Metropolitan Toronto's electricity demand during the summer of 1988 for example, strained local distribution systems to the point where the utility issued a request to its customers to limit the use of air conditioners. This is a trend which influences the relative benefits of alternatives such as solar when compared to more conventional supply options.

In the residential sector, which presently accounts for roughly one third of the total consumption of electricity, water heating is responsible for almost 20% of the total demand [1]. This represents an area where solar energy could play a key role. During the past decade, research in solar domestic hot water (SDHW) heating technologies has identified and resolved the performance and reliability problems which have had a profound effect on solar energy's credibility. The improved systems produced today have demonstrated functional performance and reliability. They have also become significantly more competitive on an economic basis, with the average cost of a residential system falling to approximately one third of 1981 values [3].

However, there are other factors which may be more important from a utility's perspective. The thermal storage in a solar water heating system inherently offers demand side management potential and with appropriate control, can be used to directly offset peak loads. With widespread implementation, this could benefit a number of utilities by eliminating or deferring the need for new capacity construction. Moreover, with market penetration levels anticipated for the year 2010, environmental benefits derived from sulphur dioxide and carbon dioxide emission reductions in Canada alone are expected to exceed $85 million annually [3]. This is consistent with the emphasis both utilities and their customers now place on considering environmental issues in energy policy formulation.

For these reasons, Energy, Mines and Resources Canada (EMR) is undertaking a study to evaluate the potential for electric utility peak load reduction through the use of solar assisted DHW systems. This study is nationwide in scope and deals with both vacuum tube and flat plate collector technologies. The Solar Calorimetry Laboratory (SCL) at Queen's University is cooperating with the WATSUN Simulation Laboratory (WSL) at the University of Waterloo to consolidate available weather and electrical load data for various locations in Canada, generate appropriate computer models and develop promising system and control concepts. These advanced strategies are compared with currently available solar systems, as well as all-electric options for reducing the peak water heating demand.

The following report details the findings of the first phase of the study which is limited to the evaluation of single family, residential systems. However, it is intended to broaden the scope of the work to include multi-family buildings, as these represent a significant portion of the residential market. In addition, the analysis conducted to date only includes the provinces of Ontario, Quebec and Nova Scotia. During subsequent phases of the study, a number of regions in Western Canada will also be evaluated.

1.2 OBJECTIVES

The objectives of this study are:

1. To design solar assisted domestic water heating systems which are specifically geared to peak load reduction.

2. To evaluate the effects of each system on local utility peak loads, load factors, energy consumption levels and customer satisfaction.

3. To assess each system's potential for a range of geographic locations and market penetration levels.

2 APPROACH

For this study, assessment of various peak shaving strategies was undertaken based on the energy and capacity savings derived from specific systems operating at different locations, and the marginal costs of energy and power at different utility demand levels. Therefore the annual performance of each system design was required for each region of interest, based on actual measured climatic data. This was determined using a combination of the WATSUN 12.2 [4] and TRNSYS 12.0 [5] computer simulation models, and required the compilation and analysis of all necessary input parameters. These included coincident climatic and utility load data for several years, and water consumption patterns which were representative of typical loads in single family dwellings.

Once these had been established, computer simulation models were developed for conventional 40 and 60 gallon electric water heaters, and current commercially available flat plate and vacuum tube solar systems. Annual simulations of these systems were then used to establish a baseline for evaluating more advanced solar strategies, as well as to determine the effects of existing solar system designs on utility peak loads, load factors and total consumption levels.

Conceptual designs and computer simulation models were then developed for several advanced systems, emphasizing energy displacement in the 80% to 100% utility load factor range. Annual simulations of these advanced systems were conducted for the same locations and data years, and the results compared with the base solar and all electric cases. For both the base and advanced strategies, the effects on utility peak loads, load factors and energy consumption levels were then determined for a range of market penetration levels. This required knowledge of the total number of electric water heaters currently installed in each region, information which was readily available from statistics Canada [6].

3 DATA PROCUREMENT AND ANALYSIS

3.1 CLIMATIC AND COINCIDENT UTILITY LOAD DATA

Hourly solar radiation and temperature data was obtained for several locations which were chosen based on data availability and adequate representation of the conditions existing within Canada. It was decided that a complete study should include detailed analyses for Halifax, Montreal, Toronto, Winnipeg, either Calgary or Edmonton, and Vancouver. Hour by hour weather data was therefore obtained from the Atmospheric Environment Service of Environment Canada for each of these locations and several calendar years. Due to budgetary and time constraints, however, phase I of this project has been limited to analyses for Toronto, Montreal and Halifax.

Once obtained, the weather data for the selected cities was compared with 'Typical Meteorological Year' [4] data for the same locations. This was done to determine which data years were most indicative of normal or average climatic conditions in each location. For each month of available data, a percentage difference value was arrived at by taking a weighted average of the differences between the means and standard deviations of radiation and temperature. To do this, radiation was weighted twice as heavily as temperature, and mean was weighted twice as heavily as standard deviation. The percentage difference values for each month were then combined into one value for the year using a root-mean-squared approach. Based on this analysis, 1988 was selected as being the most typical data year for Toronto and Halifax. Similarly, 1989 was chosen as being most indicative of normal conditions in Montreal.

Once the representative data years had been determined, coincident hourly utility load data was obtained from Ontario Hydro, Hydro Quebec and the Nova Scotia Power Corporation.

3.2 WATER CONSUMPTION

Because the technical assessment portion of this study was undertaken using computer simulation models [4,5], identification of a representative, residential hot water usage pattern was required. A number of references on hot water usage patterns were consolidated by the Watsun Simulation Laboratory, including an Ontario Hydro study [7] and a recent and comprehensive study undertaken for ASHRAE [8]. These were reviewed to identify the profile which was most appropriate for the present investigation.

Based on this exercise, it was decided to use the average usage profile determined for all households monitored in the Ontario Hydro study. Although the ASHRAE study was more recent and wider in scope, the data used to represent the Canadian situation was taken directly from the Ontario Hydro database. In addition, the ASHRAE study points out a significant climatic influence on total daily hot water usage. Therefore, it was decided to use a profile which was determined for a specific climatic region rather than an average profile which was based on monitored data from a wide variety of locations. The total daily consumption assumed for the study was 239 Litres, with the hour by hour draw volumes being shown in Table 3-1.

Table 3-1

Assumed Hourly Hot Water Usage Profile

Hour of Day	Volume (L)
1	7
2	0
3	0
4	0
5	0
6	0
7	8
8	18
9	15
10	16
11	16
12	14
13	13
14	12
15	10
16	9
17	10
18	12
19	16
20	17
21	14
22	12
23	11
24	9
Total	239

Table 3-2

Extreme Hourly Hot Water Usage Profile

Hour of Day	Volume (L)
1	0
2	0
3	0
4	0
5	0
6	0
7	20
8	40
9	30
10	30
11	25
12	25
13	25
14	20
15	20
16	15
17	15
18	25
19	30
20	30
21	25
22	25
23	25
24	25
Total	450

For the purposes of this study, the reliability with which these systems could supply hot water was also of interest. This reflects the emphasis that all utilities place on satisfying their customers's needs during all hours of the year. Therefore, simulations were also conducted assuming a larger 450 L daily load requirement which is specified by the Canadian Electrical Association as being a suitable benchmark for water heater delivery/recovery tests. This load profile is shown in Table 3-2.

3.3 MARKET POTENTIAL

The current study attempts to evaluate the potential for peak reduction through water heating in single family residences. Utility system loads, however, reflect the total energy demand in the residential, commercial and industrial sectors. Therefore, quantification of the total, single family residential water heating load is useful. This was achieved by calculating the theoretical water heating load for a single home based on the water usage profile discussed above and an assumed delivery temperature of 55°C. The theoretical

Table 3-3

Residential Water Heaters Currently Installed by Region

Region	Fuel	Number of Homes	Rate of Increase
NS	Oil	80000	0.0%
	Elec	140000	2.3%
Que	Oil	94000	0.0%
	Elec	1112000	2.0%
	Gas	42000	5.0%
Ont	Elec	1136000	1.3%
	Gas	1150000	3.9%

load was then multiplied by the total number of installed electric water heaters in each province to obtain the total load placed on the utility. The necessary information for this exercise was obtained from a recent EMR publication [3], and is based on Statistics Canada surveys for 1988 [6]. A summary is given Table 3-3 above.

The total electric water heating loads for Ontario, Quebec and Nova Scotia were calculated to be 5538 GWh/year, 5339 GWh/year and 683 GWh/year respectively.

4 SYSTEM CONCEPTS

As discussed, the systems investigated included conventional all-electric water heaters, as well as two commercially available solar plus electric designs which are suitable for the Canadian climate. The first solar assisted system studied was a flat plate package which is manufactured by Thermo Dynamics Ltd. of Dartmouth, Nova Scotia, and the second, a similarly sized vacuum tube system produced by Fournelle Energie Technologie Inc. (FET) of Montreal, Quebec. Details of these systems are given in Table 4-1 and the schematic representations in Figures 4-1 and 4-2.

In general, the advanced options which were analyzed represented component substitutions or control modifications on these basic designs. The peak reduction strategies which have been investigated to date are as follows:

1. *Increased Thermal Storage/Collector Area:* Increasing the preheat storage volume from 180 to 270 L was investigated as a means of improving the FET system's ability to reduce peak consumption during periods of low solar gain. To further enhance the potential for energy carry over on consecutive days, a third collector was then assumed for both the FET and the Thermo Dynamics systems.

2. *Off-Peak Auxiliary Charging:* In general, utilities in Canada never encounter peak demand levels between midnight and 4:00 AM. Many also consider the periods between 11:00 PM and midnight, and 2:00 PM and 4:00 PM to be suitable for load shifting. Therefore, the effects on system performance and reliability of only permitting auxiliary input during off-peak periods were investigated.

3. *Partial Off-Peak Charging:* This is similar to the off-peak strategy outlined above. However, in this case, a reduced amount of auxiliary power (i.e. 1 kW) is made available on demand. This attempts to shift a significant portion of the load without affecting the system's ability to continuously supply hot water.

4. *Increased Storage Temperature:* This strategy allows the auxiliary storage to be heated to

Table 4-1

Summary of Base SDHW Systems

	Vacuum Tube	Flat Plate
Configuration:	Closed Loop	Closed Loop
Collectors:	2 (4.52 m^2)	2 (5.20 m^2)
Preheat Tank:	180 Litres	270 Litres
Heat Exchanger:	Effectiveness = 0.85	Effectiveness = 0.85
Auxiliary Tank:	180 Litres	180 Litres
Auxiliary Element:	3 kW	3 kW
Controller:	Timer	DT* Control

* DT = Differential Temperature Control

Figure 4-1

Vacuum Tube SDHW Heating System

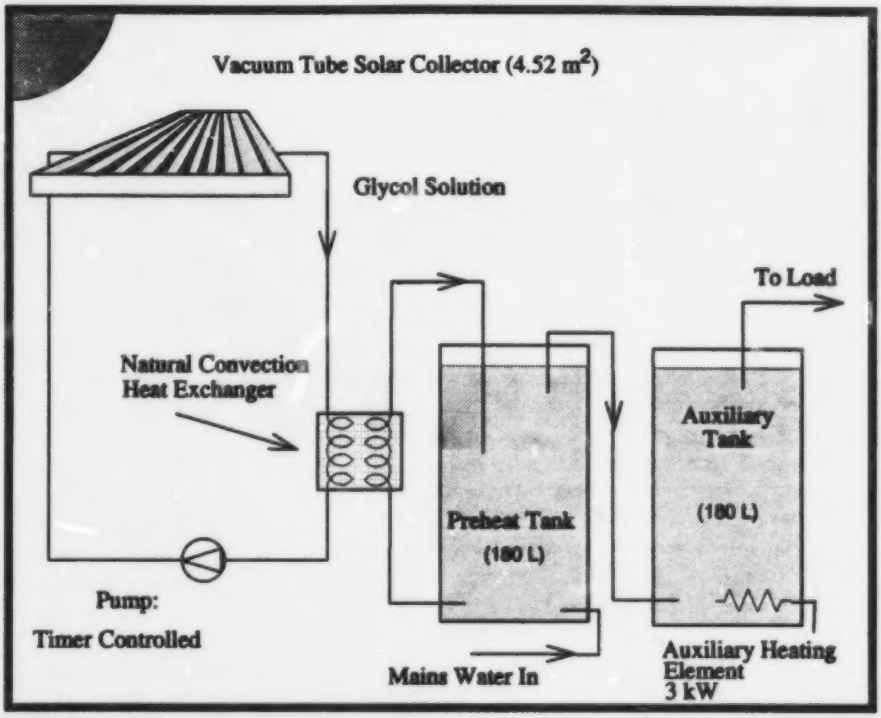
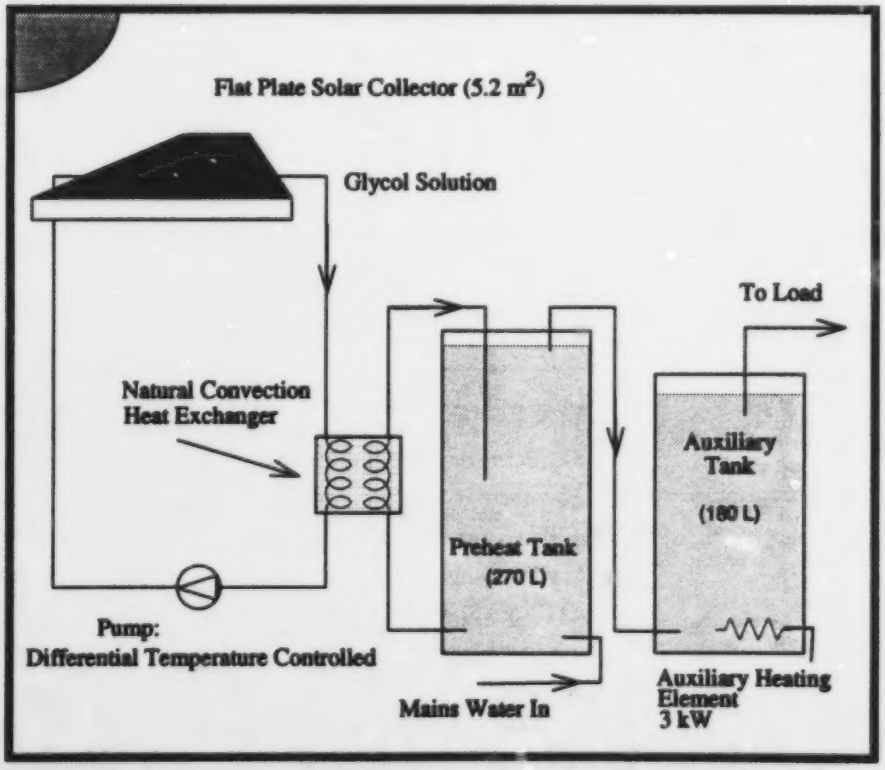


Figure 4-2

Flat-Plate SDHW Heating System



80°C, ideally during off-peak periods. A mixing valve is then used to mix water drawn from the tank with colder mains water. In this way, the desired volume of water is provided to the load at 55 °C, with smaller amounts being taken from the storage tank.

5. *Programmable Thermostat:* In this case, auxiliary backup is available throughout the day. However, the thermostat set points for peak and off-peak periods are 45°C and 64°C respectively. Therefore, water should always be available at a minimum of 45°C which is an acceptable level for personal use. An alternative to this method could involve battery backed timer control of the auxiliary element to ensure off-peak charging only. To avoid the creation of a new peak at the onset of off-peak charging (i.e. if all auxiliary elements were turned on simultaneously), a multi-staged charging strategy was also investigated.

5 EVALUATION CRITERIA

The system and control options which were considered in this study were evaluated based on a set of four criteria. These were:

1. The system's ability to reduce peak capacity requirements.
2. The effect each had on local utility load factors.
3. The annual displacement of peak, intermediate and base load energy.
4. The probability of not supplying hot water to customers.

Peak load reductions, when achieved reliably, allow utilities to defer new capacity construction when older plants are retired or when customer demands for electricity increase. Depending on the nature of the avoided supply option and the capacity factor at which it would have operated, the value of such reductions to utilities are in the order of $1000/kW to $3000/kW [1]. This includes the value of the energy savings of the alternative option when compared with a reference plan in terms of fuel, operating, maintenance and administration costs. It also includes an additional savings of five to ten percent to account for reduced transmission and distribution costs where energy is supplied or displaced at an end use location, i.e at the residential level.

In addition to capacity reduction and energy displacement, it is also necessary to consider the effects of widespread solar system use on utility load factors. In general, reduced utility load factors are undesirable as they reflect less efficient use of a utility's facilities and hence, indicate more costly generation.

The final criteria, which is the system's ability to continuously supply hot water, reflects the emphasis that all utilities place on satisfying their customers's needs during all hours of the year. Therefore, system reliability based on delivery temperature was estimated not only for a typical 239 L daily profile, but also for the case where the system was subjected to an extreme 450 L load for all days of the representative year.

6 RESULTS

6.1 GENERAL

To gain some insight into how the base solar systems and certain advanced concepts would affect actual utility loads, a number of simulations were conducted. The approach followed was to identify the benefits and shortcomings of different peak shaving concepts using the weather and load data for one province and subsequently, to extend the analysis to include the other locations being considered. Because Ontario represents a significant portion of the Canadian market, it was deemed to be the most suitable for general systems analysis. An overview of the systems studied, which are identified as cases 1 through 7 is given along with a summary of the simulation results in Table 6-1.

Systems 1 through 4 represent simple retrofits to existing electrical water heating systems. Therefore, the reliability of these systems based on their ability to supply hot water would be as good as or better than the all-electric alternative. Systems 5 through 7, however, limit the periods where electrical backup is available. For this reason, the reliability of each of these systems operating under normal load conditions was assessed by examining the hourly water delivery temperatures over the year. The results are presented in Table 6-2.

6.2 ONTARIO

Using the results of these preliminary simulations as a guideline, a more advanced system was conceptualized. This incorporates a number of the advanced component and control options discussed above, and emphasizes optimum performance with respect to the four utility-oriented evaluation criteria. In addition, system specification was undertaken to preclude unreasonable increases to existing SDHW system costs, i.e. design was based on two collector panels. A description of the system's features is given below.

Simulations of the advanced system were conducted based on the climatic and load data used in the previous analyses. To illustrate the system's effects on typical utility loads and consumer satisfaction, detailed results of these simulations are given in Tables 6-3 and 6-4 and Figures 6-1 and 6-2.

Advanced System Specification

Configuration:	Closed Loop
Collectors:	Flat Plate (5.20 m^2) or Vacuum Tube (4.52 m^2)
Preheat Tank:	180 Liters
Auxiliary Tank:	270 Litres
Auxiliary Element:	1.5 kilowatts
Heat Exchanger:	Effectiveness = 0.85
Control Strategy:	Programmable Thermostat set to 45°C During Peak Hours, with Multi-Staged Off-Peak Charging to 64°C

Table 6-1

Effects of SDHW Systems on Utility Peaks and Energy Consumption

System	Description
1	Base flat plate system.
2	Base vacuum tube system.
3	Flat plate system with 3 collectors.
4	Vacuum tube system with 3 collectors.
5	Flat plate system with 4.5 kW auxiliary during off-peak period between 24:00 and 4:00, 3 collectors, 270 L preheat tank.
6	Vacuum tube system with 4.5 kW auxiliary between 24:00 and 4:00, 3 collectors, 270 L preheat tank.
7	Vacuum tube system with 3 kW auxiliary between 24:00 and 4:00, 1 kW auxiliary on demand, 2 collectors.

System	Peak Reduct. (MW)	Annual Load (GWh)	Energy Displaced (GWh) LF<80%	LF>80%	Total
1	40	1108	540	75	615
2	65	1108	589	104	693
3	60	1108	673	105	778
4	89	1108	713	130	843
5	128	1108	622	185	807
6	139	1108	680	194	874
7	64	1108	586	103	689

Note: All numbers for 20% penetration of solar systems.
LF = Utility Load Factor.
Results for Ontario, 1988.

Table 6-2

Assessment of System Reliability

System	% of year where water delivered exceeds 40°C	45°C	50°C	55°C
5	96%	90%	78%	63%
6	96%	91%	83%	70%
7	100%	100%	100%	100%

Table 6-3 shows the annual, per system energy consumed for water heating, as well as the energy displaced by flat plate and vacuum tube systems with advanced control. The annual energy displaced by a similarly controlled all-electric system is also shown to emphasize the additional benefits derived from the solar system. The annual energy demand reductions are shown to be 3536 kWh and 4191 kWh for the flat plate and vacuum tube systems respectively. These values represent approximately 60% of the water heating load. More importantly, however, is the fact that no energy is consumed for water heating when the utility's total system load factor is above 95%.

For both the conventional all-electric system with advanced control and the solar plus electric systems with advanced control, the potential to reduce utility capacity requirements was also estimated. This was accomplished by statistically analyzing the electrical power consumed for water heating for the all-electric and solar systems with advanced control, as well as for a conventional all-electric system. For all hours during 1988 where the total utility load factor exceeded 95%, the power consumed for water heating was determined. For each system scenario, the means, standard deviations and peak power requirements were then calculated, i.e.:

$$P_{i,95\%} = \mu + 2\sigma \qquad (6.1)$$

where

$P_{i,95\%}$ is the peak power requirement for system i for a 95% confidence interval.

μ is the mean power consumed for water heating for total utility load factors above 95%.

σ is the standard deviation on power consumed for water heating at load factors above 95%.

Reductions in the per system peak demands were then estimated by subtracting the peak power levels for the advanced all-electric and advanced solar plus electric

Table 6-3
Energy Displaced Per System for Ontario

Utility Demand Level (% Peak)	Conventional System Demand kWh/yr.	Annual Energy Displaced By Systems With Advanced Control		
		All-Electric kWh/yr.	Flat-Plate kWh/yr.	Vacuum Tube kWh/yr.
30 to 35	0	0	0	0
35 to 40	0	-2	-2	-2
40 to 45	22	-75	-56	-33
45 to 50	136	-358	-207	-101
50 to 55	346	-354	-26	50
55 to 60	595	-174	190	252
60 to 65	642	55	310	358
65 to 70	1172	345	784	882
70 to 75	1150	405	823	914
75 to 80	971	445	748	824
80 to 85	662	269	504	555
85 to 90	377	239	311	333
90 to 95	139	110	132	136
95 to 100	25	25	25	25
Total	6237	930	3536	4191

systems from that for the conventional all-electric system. Based on this analysis, the peak power displacement that could be achieved at each residence with an advanced system was estimated at 1.3 kW. At Ontario Hydro, however, peak reduction would be calculated by averaging the diversified water heating demands for the all-electric and advanced solar systems over a 16 hour daily peak period, i.e. 7:00 AM to 11:00 PM. These calculations were therefore undertaken using the results for the day in 1988 when Ontario Hydro experienced its annual peak load.

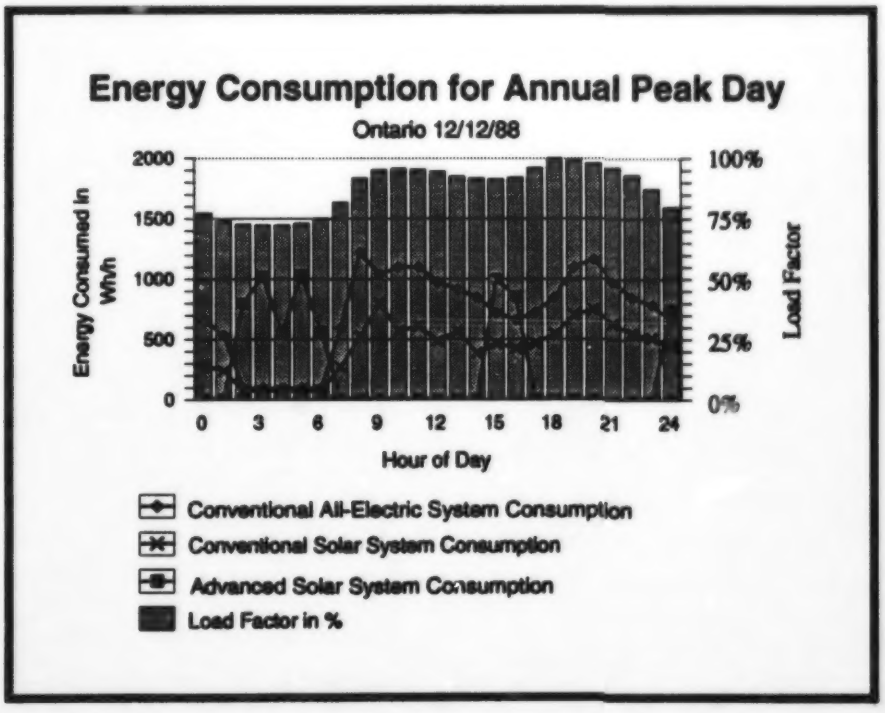
For the all-electric system, the average diversified water heating load was calculated to be 0.976 kW per household. This is marginally higher than the figure of 0.878 kW which is indicated in a 1988 Ontario Hydro study on energy consumption and demand patterns of residential water heaters in Toronto [9]. Similarly, the average water heating load for the advanced solar systems during the same 16 hour period was 0.116 kW, giving a net capacity displacement of 0.86 kW for each installed system. Moreover, because these savings are proportional to the amount of conventionally generated energy which is displaced by the systems, there is no corresponding reduction in the utility's annual load factor.

To better illustrate the solar system's ability to displace peak energy, it is useful to plot the amount of electricity required to meet a single family's water heating load during Ontario Hydro's annual peak day. This is shown in Figure 6-1 for a conventional electric water heater, a conventionally controlled solar plus electric system, and a solar plus electric system operating under the advanced control strategy outlined above. For the advanced system, the figure indicates the ability to completely eliminate the water heating load during the peak hours of the day. In addition, the maximum power demanded by the advanced solar water heaters during the off-peak hours never exceeds the daily maximum power demanded by the conventional all-electric system. Therefore, by using the charging strategy described, the creation of new utility peaks is avoided.

A system which operates under such a strategy, however, must also be able to reliably provide hot water throughout the day. Therefore the water delivery temperatures must be examined under both the average load and extreme load conditions. This has been done for the peak day and the entire year, with the results being given in Figure 6-2 and Table 6-4 respectively.

Figure 6-1

Energy Consumed for Water Heating On Annual Peak Day



Aside from increasing the amount of annual energy displaced, the results in Table 6-4 identify an additional benefit to using solar rather than advanced control on an all-electric system only. It is shown that under normal load conditions (239 L/day), the reliability of providing hot water is greater for the advanced solar plus electric systems than it would be for an all-electric system operating under the same control strategy. Therefore, under normal load conditions, the addition of solar should enhance customer satisfaction.

With the 450 L/day draw, the solar system appears to have little effect on the water delivery temperatures. However, the element capacities for the all-electric and solar plus electric systems are 3 kW and 1.5 kW respectively, i.e. the power required to meet the extreme load is significantly higher for the all-electric system. It should also be noted that in all cases, the water delivery temperature never drops below 45°C. Because water for personal use seldom exceeds this value, consumer satisfaction should be as high for these systems as it is for conventional electric water heating systems.

6.2.1 Avoided Cost Calculation

To evaluate the potential benefits to a utility, the avoided costs of the advanced solar systems and an advanced all-electric system were evaluated. Avoided cost is defined as the supply costs which are avoided when any demand or supply option is substituted for an equivalent part of a demand/supply plan. In general, an alternative option would be economically justifiable if the avoided cost exceeded the cost of pursuing the option.

There are three methods available to a utility for avoided cost calculation including the simplified levelized unit energy cost (LEUC) method, full system simulation and system incremental cost calculation [10]. The first, LEUC, evaluates an alternative option based on the lowest cost system expansion that would normally be used to meet the same load. For example, an alternative option that could supply base load in Ontario would likely be displacing nuclear generation at approximately 3.1¢/kWh. Therefore, this would be the value allotted to any unit of energy which was supplied or displaced by the alternative. Being a

Figure 6-2

Temperature of Water Delivered on Annual Peak Day

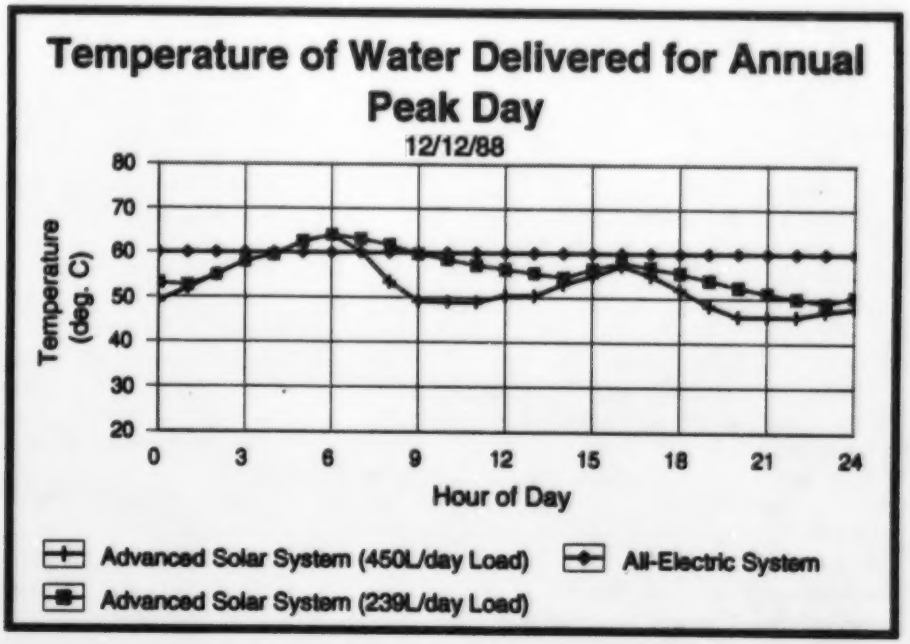


Table 6-4
System Reliability Based on Water Delivery Temperature

Temperature Criterion	Advanced Systems: All-Electric Load 1	All-Electric Load 2	Flat-Plate Load 1	Flat-Plate Load 2	Vacuum-Tube Load 1	Vacuum-Tube Load 2
T > 40°C	100%	100%	100%	100%	100%	100%
T > 45°C	100%	100%	100%	100%	100%	100%
T > 50°C	81%	67%	94%	72%	96%	75%
T > 55°C	46%	37%	65%	34%	73%	39%

Note: Load 1 = 239L/day
Load 2 = 450L/day

simplified method, LUEC calculation is useful for providing estimates or checks of an alternative option's value. However, it does have limitations in terms of accuracy and the ability to account for all factors that could significantly affect an option's avoided cost.

The most rigorous method for avoided cost determination is full simulation using detailed models such as Ontario Hydro's Load Management Strategy Testing Model [1]. Detailed computer simulation is used to characterize the reference and modified systems to determine the total cost of electricity service. The difference between the costs for the two systems is then assumed to be the avoided cost of the alternative plan. Full system simulation is a relatively complex, time-consuming activity and is generally only used for evaluating large capacity additions or displacements. Moreover, according to Ontario Hydro, it is not well suited to evaluating small changes in the utility's total load.

For these reasons, the most widely used method is system incremental cost (SIC) calculation. This method relies on the detailed simulation of a specific demand/supply plan to determine the costs which would be incurred in supplying an additional kWh of energy or an additional kW of power. These costs are then multiplied by the energy and power which is supplied or displaced by any one of a number of alternative options to arrive at that option's life-cycle avoided cost. The SIC method was chosen for the present analysis and is described in more detail below. It should also be noted that all procedures and values used in the analysis were based on a recently released Ontario Hydro report on avoided cost determination [10].

6.2.2 Economic Analysis for Ontario

The avoided cost of an option is comprised of two components, i.e. energy and power. The energy component includes factors such as fueling, operating, maintenance and administration costs, and the costs incurred to comply with local emission control regulations. The power component reflects the cost of meeting a unit increase in demand at the time of the utility's annual peak demand, i.e the cost of installing new capacity to meet the increase. The two components are therefore independent and must be accounted for separately.

The first step in calculating avoided costs involves dividing the year into different demand periods to reflect the dependency of energy costs on the time at which the energy is supplied or displaced. At Ontario Hydro, these are designated as winter and summer, peak and off-peak periods, and are identified based on number of hours. For example, the winter peak period is defined as the 1990 hours during the winter season at which the total system load is highest. The remaining 2378 hours in the winter season are then designated as off-peak hours. A similar approach is used for the summer period, with the details being given in Table 6-5. It should also be noted that the winter period includes hours from both the winter and fall and similarly, that the summer period is comprised of hours from both the summer and spring.

Another fundamental component of SIC calculation involves the definition of a reference system. For the purposes of the current study, all SIC values are based on Plan 15 of Ontario Hydro's demand/supply plan

Table 6-5

Time Periods Used for SIC Calculations, from [10]

Period	Hours in Period
Winter Peak	1990
Winter Off-Peak	2378
Summer Peak	2001
Summer Off-Peak	2391

[1]. This represents Ontario Hydro's lowest cost supply strategy as determined by detailed simulation in 1989. However, there have been significant changes in Ontario's energy policy over the past year, including an announced moratorium on any new nuclear development. Because the nuclear option was to be a major component of Ontario Hydro's chosen energy path for the next 25 years, SICs based on Plan 15 would likely be conservative numbers. The actual SIC values used for the economic analysis which follows are given in constant 1989 dollars in Table 6-6.

For the advanced solar option, the annual energy and power savings were determined for each of the four utility demand periods. This involved the analysis of Ontario Hydro's hourly total system loads for 1988, and calculation of the coincident electricity savings that were provided by the solar systems. The expected savings for one year of the system's life are given in Table 6-7, at both the residential level and at the utility's generator bus. The differences between the values under these two headings reflect the reduced transmission and distribution losses that arise when energy is displaced at the end use, and the lower capital expenditures that would be required for new transmission and distribution facilities. For Ontario Hydro, one unit of energy or power displaced at the end use is equivalent to 1.096 units of energy or power displacement at the generator bus.

The dollar values of the energy and capacity savings outlined above are determined by multiplying the savings at the bus by the SIC value for the corresponding demand period. For the purposes of illustration, savings of $166.78 for 1992 have been calculated as shown in Table 6-8. Similar cost calculations for all years of the solar system's service life are enclosed as Appendix A.

This figure of $166.78 is given in constant 1989 dollars to relate the avoided cost in 1992 to actual purchasing power for the year when the SIC values were determined. It excludes the effects of inflation and does not account for lost potential investment revenues. To account for these factors, Ontario Hydro discounts the avoided cost in any given year to 1989 using 'real terms' discount factors which are based on an annual discount rate between 4.5% and 5.75%. These factors are tabulated to the year 2015 in reference [10]. For the 1992 example year, the real discount factor is given as 1.179 and therefore, the present value of the avoided cost is determined as follows

$$PV \text{ (to 1989)} = \$166.78/1.179 = \$141.46 \qquad (6.2)$$

It is then customary for Ontario Hydro to reference the avoided cost for each year to the total kilowatts installed at the end use. With the advanced solar option, the residential capacity displaced by each system is 860 W. This translates to a present value avoided cost of $164.48 per kilowatt installed.

In cases where energy is displaced at the load centre, there is an additional avoided cost component which reflects avoided transmission and distribution (T&D) requirements. This is not an insignificant part of the total avoided cost. However, it is not captured by the detailed simulation models which are used in SIC determination. Therefore, Ontario Hydro estimates the incremental T&D expenditures that would be required to service a unit increase in demand. As is the case for the utility's discount factors, this information is tabulated to the year 2015 in reference [10].

Continuing with the example year of 1992, the incremental T&D costs are given as $41.90 per kilowatt installed at the end use. Therefore the total avoided cost for 1992 is:

$$\text{Avoided Cost for 1992} = \$164.48 + \$41.90 = \$206.38/\text{kW} \qquad (6.3)$$

To compare alternatives with different service lives, cumulative life-cycle avoided costs must be determined. Based on discussions with solar manufactures and recent field experience, currently available systems should last for a minimum of 15

years. The analysis described above was therefore undertaken for all years between 1992 and 2006, with the details being given in Appendix A. For a vacuum tube system, the cumulative avoided cost is shown to be $2878/kW or approximately $2475 per system when 1992 is used as a base year for present value calculations.

Along with many other North American utilities, Ontario Hydro has recently started to incorporate environmental externalities into its planning process. This requires some qualitative judgement with respect to the actual environmental impacts of various resource options. However, Ontario Hydro now recognizes a preference for renewables such as solar by assigning them a 10% credit in avoided cost calculations. For the vacuum tube system, therefore, the effective avoided cost is $2723.

It should be noted that identical economic analyses were undertaken for the flat plate system and the all-electric system with increased storage and advanced control. Details of the avoided cost calculations for both of these cases are given in Appendix A.

The results indicate a cumulative avoided cost $2946/kW or approximately $2533 for the flat plate system. Similarly, the avoided cost of the all-electric system with advanced control was found to be $1895/kW or $1629 per system. It should also be noted that the all-electric system has little effect on the amount of conventionally generated energy consumed for water heating. Therefore, the environmental credit discussed above does not apply when solar is not included.

Table 6-6

Ontario Hydro Plan 15: System Incremental Costs

Year	Cost of Power ($ '89/kW @ GS)	Cost of Energy ($ '89/kWh of Load @ GS) WP	WOP	SP	SOP
1990	66.6	2.34	2.02	2.33	1.76
1991	66.6	2.43	1.95	2.40	1.74
1992	66.6	2.47	1.92	2.42	1.73
1993	66.5	2.47	1.95	2.37	1.68
1994	66.5	2.46	1.94	2.30	1.66
1995	66.5	2.44	1.92	2.22	1.57
1996	66.5	2.48	1.96	2.23	1.61
1997	66.6	2.53	2.01	2.34	1.72
1998	66.6	2.56	2.05	2.35	1.80
1999	66.7	2.59	2.06	2.34	1.83
2000	66.7	2.65	2.08	2.32	1.83
2001	67.0	2.92	2.25	2.50	1.98
2002	62.7	3.13	2.37	2.65	2.11
2003	66.9	3.11	2.37	2.64	2.10
2004	72.8	2.92	2.26	2.52	2.00
2005	81.8	2.80	2.19	2.43	1.91
2006	83.4	2.85	2.19	2.48	1.87
2007	79.8	2.99	2.24	2.59	1.93
2008	76.3	3.17	2.28	2.70	1.96
2009	68.3	3.55	2.37	2.88	2.04
2010	61.0	4.11	2.51	3.06	2.08
2011	54.3	4.57	2.60	3.26	2.10
2012	51.4	5.08	2.67	3.25	1.97
2013	52.5	5.17	2.57	3.28	1.77
2014	54.6	5.27	2.49	3.28	1.60
Long Term (5 year average)	54.8	4.84	2.57	3.23	1.90

WOP = winter off peak
WP = winter peak
GS = generating source
SOP = summer off peak
SP = summer peak

Table 6-7

Estimation of Annual Energy and Power Displaced

Period	At End-Use		At Generator Bus	
	Energy Saved (kWh)	Power Saved (kW)	Energy Saved (kWh)	Power Saved (kW)
Winter Peak	1377	.860	1509	.943
Winter Off-Peak	365		400	
Summer Peak	1673		1834	
Summer Off-Peak	776		850	
Total	4191		4593	

Table 6-8

Avoided Cost for One Year of System's Life

Period	Energy Saved (kWh)	Power Saved (kW)	Energy SIC ($/MWh)	Power SIC ($/kW)	Avoided Cost ('89$)
Winter Peak	1509	.942	24.7	66.6	$100.01
Winter Off-Peak	400		19.2		$7.68
Summer Peak	1834		24.2		$44.38
Summer Off-Peak	850		17.3		$14.71
Total					$166.78

7 PRELIMINARY RESULTS FOR QUEBEC AND NOVA SCOTIA

At the time of writing this report, the authors had not obtained the necessary information for detailed economic analyses in other locations. These will therefore be the subject of future documents. Extensive performance analyses had, however, been completed for both flat plate and vacuum tube systems operating in Quebec and Nova Scotia. These analyses were based on the climatic conditions which prevail in these two provinces, and include assessment of the hourly system loads for Hydro Quebec and Nova Scotia Power respectively.

Table 7-1 shows the energy displaced by the advanced systems as a function of utility load factor.

The potential capacity reductions for each system and

Table 7-1

Energy Displaced Per System in Quebec and Nova Scotia

Utility Demand Level (% Peak)	For Advanced Solar Systems in Quebec		Nova Scotia	
	Flat-Plate kWh/yr.	Vacuum Tube kWh/yr.	Flat-Plate kWh/yr.	Vacuum Tube kWh/yr.
30 to 35	-5	-3	-6	-6
35 to 40	-55	-43	-236	-169
40 to 45	-227	-214	-172	-122
45 to 50	207	206	16	72
50 to 55	429	442	249	312
55 to 60	919	957	576	643
60 to 65	468	500	750	884
65 to 70	352	379	614	693
70 to 75	179	203	576	647
75 to 80	149	187	505	546
80 to 85	163	222	261	280
85 to 90	377	442	147	150
90 to 95	394	414	74	75
95 to 100	191	191	17	17
Total	3542	3883	3372	4023

location were calculated according to the procedure described in section 6.2. The reductions were found to be 1.36 kW per system and 2.14 kW per system respectively for the single hours where Hydro Quebec and Nova Scotia Power experienced their annual system peaks. However, to properly assess the benefits to these utilities, further analysis would be required. This would account for specific utility calculation techniques such as the 16 hour peak day average used by Ontario Hydro, and the diversification of the water heating load over this period.

Also of interest is the system reliability based on the ability to continuously supply hot water. The percentages of the year at which various water delivery temperatures are exceeded are therefore given in Table 7-2. This table contains information for vacuum tube and flat plate systems, and both the typical 239 L and the larger 450 L daily draws.

The table shows water delivery temperatures which are similar to those noted for Ontario. In addition, for the two locations and both draw profiles, vacuum tube system reliability is shown to be marginally better than that of the similarly sized flat plate system. This is consistent with the vacuum tube's theoretical performance advantage at low ambient temperatures. However, the marginal increase in annual performance must be weighed against the collector's higher cost.

Table 7-2

System Reliability Based On Water Delivery Temperature For Quebec And Nova Scotia

For Advanced Solar Systems				
Temperature	239 L/day		450 L/day	
Criterion	Flat-Plate	Vacuum-Tube	Flat-Plate	Vacuum-Tube
		Quebec		
T > 40°C	100%	100%	100%	100%
T > 45°C	100%	100%	100%	100%
T > 50°C	94%	96%	72%	75%
T > 55°C	64%	73%	33%	39%
		Nova Scotia		
T > 40°C	100%	100%	100%	100%
T > 45°C	100%	100%	100%	100%
T > 50°C	93%	96%	69%	75%
T > 55°C	61%	70%	32%	37%

8 CONCLUSIONS

Energy, Mines and Resources has commissioned a study to evaluate the potential for utility peak load reduction using solar water heating technologies. This report has outlined the results of the first phase of this ongoing investigation, including detailed analyses for single family homes in Ontario, Quebec and Nova Scotia. In addition, different system and control concepts have been evaluated to identify a single system design which was most suitable for utility integration. The performance and economics for this system were compared with those for conventional electric water heaters and currently available solar water heating systems.

As expected, the results showed conventionally controlled solar systems to be ineffective in reducing utility peak loads. This is consistent with the findings of earlier studies, and arises due to the coincidence of utility peak demands and periods of low solar gain. In this case, utilities would require the generating capacity to meet the total single-family water heating load and therefore, annual utility load factors would decrease where solar systems were used. This would in turn lead to higher costs per unit of electricity produced.

However, other system and control concepts were identified which could reliably reduce peak loads. In Ontario, optimized evacuated tube and flat plate systems could theoretically displace 860 W of the diversified capacity required for water heating in single family residences. This represents a per system capacity reduction of 942 W at Ontario Hydro's generator bus. With a 20% market penetration rate for solar systems in Ontario, this translates to peak capacity reductions in excess of 214 MW.

The optimized vacuum tube and flat plate systems could also displace 4.19 MWh and 3.54 MWh of energy per year respectively. This energy displacement would occur primarily during Ontario Hydro's winter and summer peak periods and would be proportional to capacity reductions discussed above. Therefore, unlike the conventional solar systems, the advanced system would not reduce utility load factors. Energy savings that would arise at 20% market penetration in Ontario would be between 952 GWh and 803 GWh annually, depending on whether flat plate or vacuum tube collectors were used.

For typical hot water usage patterns, delivery temperatures with the advanced systems were shown to exceed 50°C greater than 96% of the year. Moreover, this level of performance could be achieved with an auxiliary backup of only 1.5 kW. Even in cases where the system was subjected to an extreme load of 450 L during all days of the year, delivery temperatures would remain above 45°C. Because water for personal use seldom exceeds this value, customer satisfaction with these systems should be high.

The study also included detailed economic evaluations for Ontario. Based on the performance results and an assumed solar system life of 15 years, the avoided costs of the optimized vacuum tube and flat plate systems in Ontario are in the order of $2723 and $2533 respectively. Even at currently low solar system production levels, these represent the majority of the installed system costs. Additional performance evaluations also show similar potentials for regions outside of Ontario, although more detailed cost data and analyses are required.

9 FUTURE WORK

Based on the results to date, arguments could be made for utility encouragement of solar domestic hot water heating in Ontario. Moreover, performance results for Quebec and Nova Scotia appear to indicate similar situations for those two provinces. It is noted however, that Phase I of this study was based on computer simulation alone and that additional hardware development and testing is required. This is an activity which is being cooperatively addressed by Energy, Mines and Resources, Queen's University, Fournelle Energie Technologie Inc., and Thermo Dynamics Ltd.

Efforts are also being made to undertake field trials of the technology before the end of 1992. This would be a reasonable extension of the current study if additional government or utility financing was available.

Other Phase II activities will include detailed economic analyses for Quebec and Nova Scotia, and extension of the study to include a number of regions in western Canada. As discussed, these would likely include Winnipeg, either Calgary or Edmonton, and Vancouver. Because multi-family buildings represent a significant part of the residential housing market, assessment of multi-family water heating systems would also be useful. This will therefore be undertaken as time and resources permit.

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Appendix A

Detailed Avoided Cost Analysis For Solar Systems In Ontario

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1							AVOIDED COST ANALYSIS FOR ADVANCED FLAT-PLATE SYSTEM IN ONTARIO												
2			YEAR		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
3																			
4			WINTER PEAK		24.7	24.7	24.6	24.4	24.8	25.3	25.6	25.9	26.5	29.2	31.3	31.1	29.2	28	28.5
5	SIC ENERGY		WINTER OFF PEAK		19.2	19.5	19.4	19.2	19.6	20.1	20.5	20.6	20.8	22.5	23.7	23.7	22.6	21.9	21.9
6	($/MWh)		SUMMER PEAK		24.2	23.7	23	22.2	22.3	23.4	23.5	23.4	23.2	25	26.5	26.4	25.2	24.3	24.6
7			SUMMER OFF PEAK		17.3	16.8	16.6	15.7	16.1	17.2	18	18.3	18.3	19.8	21.1	21	20	19.1	18.7
8																			
9	SIC POWER ($/kW)				66.6	66.5	66.5	66.5	66.5	66.6	66.6	66.7	66.7	67	62.7	66.9	72.8	81.8	83.4
10																			
11			WINTER PEAK		1340	1340	1340	1340	1340	1340	1340	1340	1340	1340	1340	1340	1340	1340	1340
12	ENERGY		WINTER OFF PEAK		181	181	181	181	181	181	181	181	181	181	181	181	181	181	181
13	DISPLACED (kWh)		SUMMER PEAK		1729	1729	1729	1729	1729	1729	1729	1729	1729	1729	1729	1729	1729	1729	1729
14			SUMMER OFF PEAK		590	590	590	590	590	590	590	590	590	590	590	590	590	590	590
15																			
16	DISPLACED				0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942
17	POWER (kW)																		
18			WINTER PEAK		33.10	33.10	32.96	32.70	33.23	33.90	34.30	34.71	35.51	39.13	41.94	41.67	39.13	37.52	38.19
19	AVOIDED ENERGY		WINTER OFF PEAK		3.48	3.53	3.51	3.48	3.55	3.64	3.71	3.75	3.76	4.07	4.29	4.29	4.09	3.96	3.96
20	COST ($)		SUMMER PEAK		41.84	40.98	39.77	38.38	38.56	40.46	40.63	40.46	40.11	43.23	45.82	45.65	43.57	42.01	42.68
21			SUMMER OFF PEAK		10.21	9.91	9.79	9.26	9.50	10.15	10.62	10.80	10.80	11.68	12.45	12.39	11.80	11.27	11.03
22																			
23	AVOIDED POWER				62.74	62.64	62.64	62.64	62.64	62.74	62.74	62.83	62.83	63.11	59.06	63.02	68.58	77.06	78.56
24	COST ($)																		
25																			
26	TOTAL ANNUAL AVOIDED COST OF				151.36	150.16	148.68	146.46	147.48	150.68	152.00	152.52	153.02	161.22	163.56	167.02	167.17	171.62	174.63
27	ENERGY AND POWER ($)																		
28																			
29	AVOIDED COST DISCOUNTED TO				128.36	120.22	112.72	105.14	100.39	97.60	93.31	88.78	84.40	84.54	81.70	79.46	75.78	74.19	71.75
30	1992 ($)																		
31																			
32	DISCOUNTED AVOIDED COST OF POWER				149.28	139.80	131.07	122.26	116.74	113.48	108.50	103.23	98.14	98.30	95.00	92.39	88.11	86.27	83.43
33	AND ENERGY ($/kW @ END USE)																		
34																			
35	T&D INCREMENTAL COST SAVINGS				41.98	42.05	42.12	42.2	42.46	42.61	42.78	42.94	43.15	43.42	43.6	43.77	43.95	44.14	44.29
36	DISCOUNTED TO 1992 ($/kW @ END USE)																		
37																			
38	TOTAL ANNUAL AVOIDED COST IN 1992				191.26	181.85	173.19	164.46	159.20	156.09	151.28	146.17	141.29	141.72	138.60	136.16	132.06	130.41	127.72
39	DOLLARS ($/kW @ END USE)																		
40																			
41	CUMULATIVE PRESENT VALUE FOR SOLAR SYSTEM ($/kW), PV to 1992								2678.05										
42																			
43	CUMULATIVE PRESENT VALUE FOR SOLAR SYSTEM ($/SYSTEM), PV to 1992								2303.12										
44																			
45	CUMULATIVE PRESENT VALUE FOR SYSTEM WITH 10% ENVIRONMENTAL CREDIT								2533.43										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1							AVOIDED COST ANALYSIS FOR ADVANCED EVACUATED TUBE SYSTEM IN ONTARIO												
2			YEAR		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
3																			
4			WINTER PEAK		24.7	24.7	24.6	24.4	24.8	25.3	25.6	25.9	26.5	29.2	31.3	31.1	29.2	28	28.5
5	SIC ENERGY		WINTER OFF PEAK		19.2	19.5	19.4	19.2	19.6	20.1	20.5	20.6	20.8	22.5	23.7	23.7	22.6	21.9	21.9
6	($/MWh)		SUMMER PEAK		24.2	23.7	23	22.2	22.3	23.4	23.5	23.4	23.2	25	26.5	26.4	25.2	24.3	24.8
7			SUMMER OFF PEAK		17.3	16.8	16.6	15.7	16.1	17.2	18	18.3	18.3	19.8	21.1	21	20	19.1	18.7
8																			
9	SIC POWER ($/kW)				66.6	66.5	66.5	66.5	66.5	66.6	66.6	66.7	66.7	67	62.7	66.9	72.8	81.6	83.4
10																			
11			WINTER PEAK		1509	1509	1509	1509	1509	1509	1509	1509	1509	1509	1509	1509	1509	1509	1509
12	ENERGY		WINTER OFF PEAK		400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
13	DISPLACED (kWh)		SUMMER PEAK		1834	1834	1834	1834	1834	1834	1834	1834	1834	1834	1834	1834	1834	1834	1834
14			SUMMER OFF PEAK		850	850	850	850	850	850	850	850	850	850	850	850	850	850	850
15																			
16	DISPLACED				0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942
17	POWER (kW)																		
18			WINTER PEAK		37.27	37.27	37.12	36.82	37.42	38.18	38.63	39.08	39.99	44.06	47.23	46.93	44.06	42.25	43.01
19	AVOIDED ENERGY		WINTER OFF PEAK		7.68	7.80	7.76	7.68	7.84	8.04	8.20	8.24	8.32	9.00	9.48	9.48	9.04	8.76	8.76
20	COST ($)		SUMMER PEAK		44.36	43.47	42.18	40.71	40.90	42.92	43.10	42.92	42.55	45.85	48.60	48.42	46.22	44.57	45.48
21			SUMMER OFF PEAK		14.71	14.28	14.11	13.35	13.69	14.62	15.30	15.56	15.56	16.83	17.94	17.85	17.00	16.24	15.90
22																			
23	AVOIDED POWER				62.74	62.64	62.64	62.64	62.64	62.74	62.74	62.83	62.83	63.11	59.06	63.02	68.58	77.06	78.56
24	COST ($)																		
25																			
26	TOTAL ANNUAL AVOIDED COST OF				166.76	165.46	163.82	161.20	162.49	166.49	167.97	168.63	169.24	178.86	182.31	185.70	184.90	188.87	191.71
27	ENERGY AND POWER ($)																		
28																			
29	AVOIDED COST DISCOUNTED TO				141.46	132.47	124.20	115.72	110.61	107.69	103.11	98.15	93.35	93.79	91.06	88.34	83.82	81.55	78.76
30	1989 ($)																		
31																			
32	DISCOUNTED AVOIDED COST OF POWER				164.48	154.04	144.42	134.56	128.62	125.22	119.90	114.13	108.55	109.06	105.89	102.72	97.46	94.83	91.58
33	AND ENERGY ($/kW @ END USE)																		
34																			
35	*T&D INCREMENTAL COST SAVINGS*				41.98	42.05	42.12	42.2	42.46	42.61	42.78	42.94	43.15	43.42	43.6	43.77	43.95	44.14	44.29
36	DISCOUNTED TO 1989 ($/kW @ END USE)																		
37																			
38	TOTAL ANNUAL AVOIDED COST IN 1989				206.46	196.09	186.54	176.76	171.08	167.83	162.68	157.07	151.70	152.48	149.49	146.49	141.41	138.97	135.87
39	DOLLARS ($/kW @ END USE)																		
40																			
41	CUMULATIVE PRESENT VALUE FOR SOLAR SYSTEM ($/kW), PV to 1992								2877.84										
42																			
43	CUMULATIVE PRESENT VALUE FOR SOLAR SYSTEM ($/SYSTEM), PV to 1992								2474.94										
44																			
45	CUMULATIVE PRESENT VALUE FOR SYSTEM WITH 10% ENVIRONMENTAL CREDIT								2722.44										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	AVOIDED COST ANALYSIS FOR ADVANCED ALL-ELECTRIC SYSTEM IN ONTARIO																		
2			YEAR		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
3																			
4			WINTER PEAK		24.7	24.7	24.6	24.4	24.8	25.3	25.6	25.9	26.5	29.2	31.3	31.1	29.2	28	28.5
5	SIC ENERGY		WINTER OFF PEAK		19.2	19.5	19.4	19.2	19.6	20.1	20.5	20.6	20.8	22.5	23.7	23.7	22.6	21.9	21.9
6	($/MWh)		SUMMER PEAK		24.2	23.7	23	22.2	22.3	23.4	23.5	23.4	23.2	25	26.5	26.4	25.2	24.3	24.8
7			SUMMER OFF PEAK		17.3	16.8	16.6	15.7	16.1	17.2	18	18.3	18.3	19.8	21.1	21	20	19.1	18.7
8																			
9	SIC POWER ($/kW)				66.6	66.5	66.5	66.5	66.5	66.6	66.6	66.7	66.7	67	62.7	66.9	72.6	81.8	83.4
10																			
11			WINTER PEAK		815	815	815	815	815	815	815	815	815	815	815	815	815	815	815
12	ENERGY		WINTER OFF PEAK		-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361
13	DISPLACED (kWh)		SUMMER PEAK		847	847	847	847	847	847	847	847	847	847	847	847	847	847	847
14			SUMMER OFF PEAK		-372	-372	-372	-372	-372	-372	-372	-372	-372	-372	-372	-372	-372	-372	-372
15																			
16	DISPLACED				0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942	0.942
17	POWER (kW)																		
18			WINTER PEAK		20.13	20.13	20.05	19.89	20.21	20.62	20.86	21.11	21.60	23.80	25.51	25.35	23.80	22.82	23.23
19	AVOIDED ENERGY		WINTER OFF PEAK		-6.93	-7.04	-7.00	-6.93	-7.08	-7.26	-7.40	-7.44	-7.51	-8.12	-8.56	-8.56	-8.16	-7.91	-7.91
20	COST ($)		SUMMER PEAK		20.50	20.07	19.48	18.80	18.89	19.82	19.90	19.82	19.65	21.18	22.45	22.36	21.34	20.58	21.01
21			SUMMER OFF PEAK		-6.44	-6.25	-6.18	-5.84	-5.99	-6.40	-6.70	-6.81	-6.81	-7.37	-7.85	-7.81	-7.44	-7.11	-6.98
22																			
23	AVOIDED POWER				62.74	62.64	62.64	62.64	62.64	62.74	62.74	62.83	62.83	63.11	59.06	63.02	68.58	77.06	78.56
24	COST ($)																		
25																			
26	TOTAL ANNUAL AVOIDED COST OF				90.00	89.56	88.99	88.56	88.68	89.52	89.41	89.52	89.76	92.60	90.61	94.36	98.12	105.45	107.93
27	ENERGY AND POWER ($)																		
28																			
29	AVOIDED COST DISCOUNTED TO				76.33	71.70	67.47	63.58	60.37	57.91	54.89	52.10	49.51	48.56	45.26	44.89	44.48	45.53	44.34
30	1989 ($)																		
31																			
32	DISCOUNTED AVOIDED COST OF POWER				88.76	83.38	78.45	73.93	70.19	67.33	63.82	60.59	57.57	56.46	52.63	52.20	51.72	52.94	51.56
33	AND ENERGY ($/kW @ END USE)																		
34																			
35	T&D INCREMENTAL COST SAVINGS				41.98	42.05	42.12	42.2	42.46	42.61	42.78	42.94	43.15	43.42	43.6	43.77	43.95	44.14	44.29
36	DISCOUNTED TO 1989 ($/kW @ END USE)																		
37																			
38	TOTAL ANNUAL AVOIDED COST IN 1989				130.74	125.43	120.57	116.13	112.65	109.94	106.60	103.53	100.72	99.88	96.23	95.97	95.67	97.08	95.85
39	DOLLARS ($/kW @ END USE)																		
40																			
41	CUMULATIVE PRESENT VALUE FOR SOLAR SYSTEM ($/kW), PV to 1992							1894.65											
42																			
43	CUMULATIVE PRESENT VALUE FOR SOLAR SYSTEM ($/SYSTEM), PV to 1992							1629.40											